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PEOPLES ENERGY
Peoples Gas
North Shore Gas

DEPT. OF TRANSPORTATION DOCKETS

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June 5, 2000

Dockets Facility
U. S. Department of Transportation
Room PL-401
400 Seventh Street, SW
Washington, DC 20590-0001

Subject: 49 CFR Part 195 43
Docket No. RSPA-99-6355; Notice 3
Pipeline Safety: Pipeline Integrity Management
In High Consequence Areas

The Peoples Gas Light and Coke Company (PGLC) is a combination distribution (LDC) and transmission company that distributes natural gas to approximately 800,000 residential, 45,000 commercial and 4,300 industrial customers all within the city limits of Chicago, Illinois.

PGLC operates 367 miles of intrastate transmission pipeline (about 75 miles of which are within a storage field) and a 14-mile hazardous liquids pipeline outside Chicago City limits. Within the City, PGLC operates 58 miles of transmission pipeline in conjunction with approximately 4,000 miles of distribution main and 495,000 service lines.

Although PGLC will not be subject specifically to this proposed rule, it may be involved in the future when, as stated under "Comments Received in the Docket", RSPA issues proposed system integrity rules later this year that apply to those hazardous liquid operators not covered by this initial action and to all natural gas transmission pipeline operators. PGLC anticipates that those proposed rules will closely resemble this current rulemaking. In that light, PGLC has reviewed the subject Notice of Proposed Rulemaking and offers the following comments. These are organized under section headings used by RSPA in the NPRM. Only those sections for which PGLC has comments are addressed.

Accident Analysis

The last paragraph says the integrity management of pipelines will require internal inspection or pressure testing (one or the other) in addition to several other activities. Later in the preamble and in the proposed rule itself, this is modified somewhat by allowing new technologies to be used for evaluation. Since there are apparently no "new technologies" available now, this effectively forces all initial evaluations to require smart pigs or hydrostatic testing. Future interpretations as to what constitutes compliance will

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come back to this statement so that there will be no way to "prove" integrity without either a smart pig run or a recent pressure test. Additional comments about "new technologies" are under the proposed rule section below.

There is no mention of third party damage as the leading cause of pipeline accidents. In an effort to address damage to pipelines caused by excavation, RSPA's Office of Pipeline Safety (OPS) sponsored the Common Ground best practices initiative and the resulting incipient formation of the Common Ground Alliance. Although OPS praised the efforts that produced the compilation of those best practices, no time has been given to implement them and assess their impact on pipeline safety. If excavation damage can be reduced, the necessity for pipeline integrity management will also be significantly reduced and the complex, burdensome rule being proposed could be greatly simplified or not promulgated.

No reasonable operator wants a pipeline accident on its system. As stated under "Operator-Developed Integrity Management Programs", OPS found that liquid pipeline operators have made progress in developing and implementing formalized management systems to address the most significant integrity threats to their pipeline systems and that integrated risk-based programs are becoming more common. OPS should give its Risk Management Demonstration Program a chance to address the problem before imposing this pipeline integrity rule on the industry. The risk management pilot program has not yet concluded and no analysis of its effectiveness has been published. How do we know if such an initiative will work to improve pipeline safety without a rather prescriptive new rule such as is proposed?

High Consequence Areas

The last paragraph says that high consequence areas will be identified on OPS's National Pipeline Mapping System. Does this mean that OPS is going to determine where all the high consequence areas are? There is currently nothing in the proposed rule or the preamble that states who is to determine the limits of high consequence areas. It would be easier for operators to comply with a rule that identifies the areas of concern even though it would be prescriptive. If determination of high consequence areas is left up to each operator, there will be a significant body of interpretation required regarding marginal areas. One operator could include a marginal area as a high consequence area while another operator with pipeline in the same vicinity may not. Such possibilities do not support clarity and consistency in the regulations.

High Population Areas and Other Populated Areas

Use of Census Bureau data to define these areas should make things easier for operators to determine where they are. Although it is very prescriptive, everyone will have the same database so arguments should be at a minimum.

Unusually Sensitive Areas (USAs)

As described in this section of the preamble, OPS has spent several years and considerable effort in consultation, meetings, etc. with stakeholders to determine a proposed definition for unusually sensitive areas. Yet in the fourth paragraph it is suggested that other resources should be considered as part of unusually sensitive areas. Adding any or all of the other areas listed basically negates those previous efforts

expended in defining USAs including getting stakeholder input and performing pilot tests.
This is also another example of OPS issuing a regulation before the results of a pilot program are collected and analyzed. There is little point in establishing and conducting pilot tests if you do not or cannot wait for the results.

Commercially Navigable Waterways
Use of a term such as "substantial likelihood" in a definition does nothing for providing regulations that are clear, concise and easily understood - goals that OPS espouses in other rulemakings. Determining "navigable waterways" has been subject to interpretation for years in the pipeline safety regulations.
OPS explains that there is a national database that includes commercially navigable waterways. It would be more useful for OPS to reference that database to determine navigable waterways, as they propose to reference the Census Bureau database to determine populated areas. That way there will be no need for interpreting where "substantial likelihood" of commercial traffic might occur. Including the data on the National Mapping System will provide easy access for all constituents.

When Must the Baseline Assessment Be Completed?
OPS is proposing to allow operators to take credit for integrity assessments done within five years of the final rule toward the required baseline assessment. This is a welcome provision that should save costs for many operators that have been gearing up and performing pipeline integrity reviews in recent years.

What Remedial Actions Should Be Taken?
Comments are requested on whether the rule should contain specific time lines for conducting repairs. With the number of variables associated with pipeline repairs, depending on the type or magnitude of the repair required, specific time limits written into the rule will be an undue burden to be placed on operators. OPS has recently proposed a relaxation of a specific time frame for confirmation or revision of MAOP in the periodic update docket for Part 192. Such actions could become routinely necessary for Part 195 if specific repair windows are included in the regulation.

Integrity Assessment Tools
#2. Pressure Testing
The last sentence in the first paragraph states "An operator must test to a minimum of 1.25 times the maximum operating pressure because research has shown that at that level of pressure all critical defects can be identified and eliminated." While this is consistent with the required test pressure for new pipelines under Part 195, it raises the question of why Part 192 calls for pressure tests to be at a minimum of 1.5 times MAOP in Class 3 and 4 locations – essentially "high consequence areas". Based on the referenced research and in the interest of consistency of the pipeline regulations (a stated goal of OPS), will this level of pressure test be allowed for integrity assessment of gas transmission lines when that rule is proposed?

Executive Order 12866 and DOT Regulatory Policies and Procedures
This may not be a significant rulemaking within the guidelines of the referenced Executive Order and DOT policies and procedures, but it will be significant to the pipeline operators that will have to comply with it. The level of effort required to develop the program and all the supporting data is far from a trivial task. When added over the entire pipeline industry, which it should be since eventually all but LDCs will be involved, the hours and costs will be enormous. For example, one textbook on risk management for pipelines is over 400 pages long and it only provides a framework for a risk management program. The modeling of the pipeline, development of risk factors, assigning values and weights to the factors and all the other tasks to produce a viable program need to be provided and input by the operator. PGLC estimates that developing the initial program will cost on the average of $100,000 per operator, which will be significantly more than the industry total of $1.5 million estimated by OPS.
The OPS estimate of the cost of initial and ongoing assessments is similarly far understated. They estimate the baseline assessment to cost $7.9 million for 29,300 miles of pipeline estimated to be impacted by the rule. That averages $270 per mile for either a smart pig inspection or a hydrostatic test. In the spring of 2000, PGLC performed an MFL smart pig inspection of a 55 mile long pipeline. The smart pig portion alone averaged $2818 per mile which does not include preparation, a cleaning run, a geometry pig run (also being required by this NPRM), handling and disposal of environmental wastes from the pipeline and other incidental costs. Finally there seems to be no allowance in the OPS estimate for loss of business cost while a pipeline is shutdown in preparation for a smart pig run or during a hydrostatic test.

The following comments are on the proposed rule itself.

Section 195.450 Definitions
In subparagraph (2) under Emergency flow restriction device the list of communication linkages between the pipeline control center and the RCV is too restrictive. By naming only those four options there is no allowance for future technological advances or for other currently used methods such as radio or cellular telephone.

Section 195.452 Pipeline Integrity Management in High Consequence Areas
The paragraphs in this section each start with a question. This is a rather unconventional regulatory format and is not consistent with the rest of Part 195. If such format is to remain, however, paragraphs (h), (i) and (k) need to have the first sentence in question form to be consistent with the rest of the paragraphs.

Section 195.452(c)(1): What must be in the baseline assessment plan?
[The following comments also apply to Sections 195.452(d)(1) and 195.452(j)(1).]
Besides a pressure test or an internal inspection tool, the only other method allowed for integrity assessment is "new technology". That term implies the application of as yet undiscovered science to perform the required task. It does not allow for use of current technology such as sonic or optical methods if future improvements should be made to make them feasible for pipeline integrity assessment work.

The reference to technology also does not allow the use of other integrity assessment tools such as statistical analysis. For example, PGLC has for years used an in-house developed computer model that assigns a ranking to each segment of our distribution system based on a series of weighted factors physically attributable to each segment. The factors include indexes for breaks, cracks, observed pipe condition, pipe coupon analysis, number of repairs performed, pipe diameter, operating pressure, and its location (business district vs. residential area). The influence of this system on pipe replacement decisions over the past several years has yielded a noticeable reduction in the number of main leaks reported. PGLC is convinced that this is a powerful integrity assessment tool without the need for other intrusive methods.
Although PGLC developed its own segment ranking system, we are aware of at least one commercially available similar system and numerous others created by other operators for their own use. Such statistical methods have proven effective and should be allowed as an alternative within this rule.

Section 195.452(g): What remedial action must be taken?
The second sentence which is currently written "An operator must evaluate and repair all defects that could reduce a pipeline's integrity." does not say what we believe OPS means. As written, only defects that reduce integrity need to be evaluated. How can such defects be determined if all data collected is not reviewed? This requirement would be clearer and more accurate if stated as follows: "An operator must evaluate all significant anomalies indicated and then repair all defects that could reduce the integrity of the pipeline."

Section 195.452(g)(4)
For clarity and accuracy, this section should be written as follows: "Data that indicate~~s~~ anomalies longitudinal in orientation have ~~has~~ priority over ~~transverse~~ data that indicate anomalies are transverse." It is not the data that are transverse; it is the anomalies.

Section 195.452(i)
The third sentence which begins "Such actions include, but are not limited to . . ." should be revised to say "Such actions <u>may</u> include, but are not limited to . . ." As currently written the implication is that all of the listed actions must be undertaken as a minimum where only one or a few may be sufficient to mitigate a potential threat to the pipeline in a high consequence area.

Appendix C To Part 195 - - Prioritizing Risk Factors
The first sentence says this appendix gives "guidance". Does that mean that the information in the appendix is non-mandatory? There is mixed use of the terms "should" and "must" throughout the appendix which further confuses its intent. This needs to be clarified by OPS.
In item I the eighth bullet refers to natural gas under Product Transported. This seems inappropriate since this proposed rule is for pipelines that transport hazardous liquids.
The tenth bullet under item I could be clarified by changing it to read "Size (higher volume release if ~~the~~ <u>a larger</u> pipe ruptures).

In item II (b) the first and second bullets both use the phrase "not exceeding x months". Since "x" is used in both, does that mean that repair period is intended to be the same for both types of anomalies? If not, a different variable should be used in one of the bullets.
In the "Line Size or Volume Transported" table the line sizes are designated in inches only. To be consistent with the remainder of Part 195, the metric equivalents should also be shown.
In the "Product Transported" table the temperatures stated should indicate degrees F for clarity and accuracy. In addition, the metric equivalents should be included for consistency.

PGLC appreciates the opportunity to comment on this Notice of Proposed Rulemaking

Sincerely,

C L Thompson

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